REPORT TO THE BOARD OF DIRECTORS

CONDUCT A PUBLIC HEARING FOR CONSIDERATION OF RATE RESTRUCTURING FOR RATE SCHEDULES 1, 3, 5, 7, 8, 9, 10, 11, 18, 19 AND 20

Issue:

Should the Trinity Public Utilities District (District) Board of Directors (Board) consider a Rate Restructuring to accelerate the Rate changes adopted in January 2022 and implement a Wholesale Power Cost Adjustment?

Background and Discussion:

The Board, at its November 9, 2023 meeting, requested that Staff consider implementation of a Wholesale Power Cost Adjustment to the District's Rate Schedules, in lieu of the Drought Relief Surcharge. The Wholesale Power Cost Adjustment would potentially be adjusted from the Base Rate twice per year, if the cost of wholesale power from the Western Area Power Administration (WAPA) is adjusted, while operational expenses would be built around the System Access Charge and the Base Rate.

Annual power acquisition costs have fluctuated from a low of $1.3 million to a high of $4.9 million since Fiscal Year 17/18. The Drought Relief Surcharge was implemented to account for the fluctuating cost of power due to drought, or lack thereof, generating approximately $1.8 million per year when in effect. The Surcharge is adjusted based on a determination of whether or not the Water Year is "above average" in the April Bulletin 120 Report from the California Department of Water Resources. However, WAPA adjusts wholesale power costs in April and October, so the Surcharge can lag behind the power cost adjustment by up to 18 months. When combined with inflationary pressures and the District's strategy of keeping reserves low, the District now faces negative reserves in the Budget Forecast.

At the December 14, 2023 meeting, staff provided Scenario 1, attached, which includes a Budget Forecast Summary, the impact of a proposed Rate Restructure to existing Rate Schedules, and Historical Power Costs. Scenario 1 included accelerating implementation of existing approved rate increases to the previously approved Year 2025 amounts. The Board requested that staff return with an additional proposal to better address forecasted negative Reserves, and to consider both increasing rates and reducing expenses.

The attached Scenario 2 accelerates existing changes already approved to the Year 2025 Rates and includes an additional increase to account for operational expenses. The Scenario provides the total proposed new rate, however, upon further direction from the Board, the Rate Schedules would be calculated to reflect a Base Rate plus a Wholesale Power Cost Adjustment. For example, if Scenario 2 is selected, the Residential Energy Charge would be $0.04682 and the Wholesale Power Cost Adjustment would be $0.0344, for a total of $0.08122.

Fiscal Analysis:

The proposed rate restructuring will allow the District to adjust rates based on wholesale power costs twice per year, covering increasing operational expenses due to inflationary pressure, while continuing its strategy of keeping reserves low.

Alternatives:

The Board has the option to:

1. Direct Staff to proceed with Scenario 1, conduct a Rate Presentation and Public Hearing on January 30, 2024 and return for final consideration at the February 8, 2024 Board Meeting.
2. Direct Staff to proceed with Scenario 2, conduct a Rate Presentation and Public Hearing on January 30, 2024, and return for final consideration at the February 8, 2024 Board Meeting.
3. Provide Staff with alternate direction.

Conclusions and Recommendations:

The proposed rate restructuring will more accurately reflect wholesale power costs, while also addressing shortfalls in the Forecast Summary. Staff recommends that the Board direct Staff to proceed with Scenario 2, conduct a Rate Presentation and Public Hearing on January 30, 2024, and return for final consideration at the February 8, 2024 Board Meeting.

Paul Hauser

Paul Hauser

Dated: 1/5/2024

Forecast Summary

Revenues	20/21 (Actual)	21/22 (Actual)	22/23 (Preliminary)	21-23 % Growth	23/24 (Budgeted)	24/25 (Projected)	25/26 (Projected)	26/27 (Projected)	27/28 (Projected)
Energy sales	11,865,205	12,167,458	12,102,650	1.0%	13,342,733	15,865,447	15,865,447	15,865,447	15,865,447
Surcharge receipts	1,525,030	1,673,534	1,639,727	3.8%	-	-	-	-	-
Other receipts	2,373,454	1,979,544	3,960,542	33.4%	4,356,526	2,136,348	2,160,230	2,190,317	2,221,091
Total	15,763,689	15,820,536	17,702,919	6.2%	17,699,259	18,001,795	18,025,677	18,055,764	18,086,538
Expenses									
Power acquisition	3,221,280	5,152,873	4,218,848	15.5%	4,365,770	4,788,712	4,794,462	4,800,384	4,806,484
Operations & maintenance	4,407,884	4,495,731	5,162,445	8.6%	5,038,126	5,118,957	5,201,159	5,284,757	5,369,776
Customer accounts	925,935	718,497	745,553	-9.7%	824,238	836,601	849,150	861,887	874,816
Administrative & general	1,258,362	1,672,324	2,091,967	33.1%	2,097,985	2,141,714	2,166,519	2,212,428	2,259,471
Debt & financing	1,629,058	2,486,462	2,549,585	28.3%	2,572,224	2,488,665	2,492,016	2,493,416	2,398,016
Total	11,442,519	14,525,887	14,768,398	14.5%	14,898,342	15,374,650	15,503,306	15,652,872	15,708,562
Available for capital	4,321,169	1,294,649	2,934,521	-16.0%	2,800,917	2,627,145	2,522,371	2,402,892	2,377,976
Capital outlay	6,324,646	5,710,088	7,817,194	11.8%	6,470,780	5,144,727	5,713,423	5,383,149	5,153,921
Bond/Loan proceeds	-	8,940,400	-		-	-	-	-	-
County/MCMS funding	-	-	-		-	-	-	-	-
County/MCMS repayments	143,638	168,227	97,931	-15.9%	-	-	-	-	-
Change in total reserves	(1,859,839)	4,693,188	(4,784,742)	78.6%	(3,669,863)	(2,517,582)	(3,191,052)	(2,980,257)	(2,775,945)
Reserves balances (end of year)									
Encumbered	1,185,720	690,400	390,045	-33.6%	1,404,492	1,446,627	1,468,011	1,489,710	1,511,730
Restricted Reserves	55,247	8,719,967	5,083,384	4550.6%	66,179	12,341	12,635	12,935	13,243
Customer funds	1,167,026	916,130	913,991	-10.8%	892,195	872,542	861,216	852,889	844,562
Dedicated	386,667	75,000	-	-50.0%	-	-	-	-	-
Total other reserves	2,794,660	10,401,497	6,387,420	64.3%	2,362,866	2,331,510	2,341,861	2,355,534	2,369,536
Contingency fund	2,557,352	(356,297)	(1,126,962)	-72.0%	(772,271)	(3,502,835)	(6,954,238)	(9,698,168)	(12,238,115)
Total reserves	5,352,012	10,045,200	5,260,458	-0.9%	1,590,595	(1,171,325)	(4,612,377)	(7,342,634)	(9,868,580)

Includes $2.0 million of FEMA/OES expected reimbursement from 2022-2023 Winter storms
Updated to reflect lower power costs offset by $2.2million true-up Adjustment from Western
Includes the potential increase to revenue moving from year 2 directly to year 4 rates and Access charge

Scenario 1

TRINITY PUD
HISTORICAL POWER COSTS
FY 11/12 THROUGH FY 23/24

FISCAL YEAR	KWH USAGE	ANNUAL POWER ACQUISITION COSTS	COST PER KWH
11/12	98,245,472	$ 2,131,005	$ 0.0217
12/13	98,046,742	$ 2,479,917	$ 0.0253
13/14	98,181,828	$ 2,425,626	$ 0.0247
14/15	94,241,352	$ 3,318,858	$ 0.0352
15/16	101,034,659	$ 3,979,409	$ 0.0394
16/17	108,676,572	$ 3,020,017	$ 0.0278
17/18	109,676,241	$ 1,360,867	$ 0.0124
18/19	107,665,663	$ 2,420,621	$ 0.0225
19/20	114,245,057	$ 2,936,470	$ 0.0257
20/21	127,947,935	$ 3,020,571	$ 0.0236
21/22	127,316,866	$ 4,948,466	$ 0.0389
22/23	122,273,970	$ 4,012,327	$ 0.0328
23/24	120,000,000	$ 4,130,944	$ 0.0344

FY 23/24 kWh sales originally assumed to be equal to FY 22/23.
Current analysis reflects lower kWh sales through December 2023.
FY 23/24 kWh sales have been adjusted down to reflect lower sales.

Trinity PUD
Rate Restructure - Year 3 impact
kWh Usage and Meter Count as of June 30, 2023
Increase Equal to DRS added Back to 2/11/2023 rates - Zone A

	a	b	c	.017/a	(b-a)*c*12 (b-a)*c
			# of Meters and YTD kWH at June 2023	DRS as % of current rates	Revenue Generated by rate change
Proposed Residential Rates (Zone A) - Rate Schedule No. 1					
Rate Component	2/11/2023	2/11/2024			
System Access Charge ($/Meter)	$ 31.00	$ 38.00	2523		$ 211,932
Energy Charge ($/kWh)	$ 0.05983	$ 0.07683	33,170,520	28%	$ 563,899
Proposed Residential Rates (Zone B) - Rate Schedule No. 1					
Rate Component	2/11/2023	2/11/2024			
System Access Charge ($/Meter)	$ 31.00	$ 38.00	3,247		$ 272,748
Energy Charge ($/kWh)	$ 0.07122	$ 0.07683	33,356,281	24%	$ 187,129
Proposed Commercial Rates (Zone A) - Rate Schedule No. 3					
Rate Component	2/11/2023	2/11/2024			
System Access Charge ($/Meter)	$ 46.50	$ 57.00	705		$ 88,830
Energy Charge ($/kWh)	$ 0.07758	$ 0.09930	19,700,046	28%	$ 427,932
Proposed Commercial Rates (Zone B) - Rate Schedule No. 3					
Rate Component	2/11/2023	2/11/2024			
System Access Charge ($/Meter)	$ 46.50	$ 57.00	436		$ 54,936
Energy Charge ($/kWh)	$ 0.08761	$ 0.09930	6,581,109	19%	$ 76,949
Proposed High Impact Rates (Zone A) - Rate Schedule No. 20					
Rate Component	2/11/2023	2/11/2024			
System Access Charge ($/Meter)	$ 82.50	$ 120.00	43		$ 19,350
Energy Charge ($/kWh)	$ 0.11656	$ 0.14920	2,975,347	28%	$ 97,106
Proposed High Impact Rates (Zone B) - Rate Schedule No. 20					
Rate Component	2/11/2023	2/11/2024			
System Access Charge ($/Meter)	$ 82.50	$ 120.00	221		$ 99,450
Energy Charge ($/kWh)	$ 0.12857	$ 0.14920	14,273,819	13%	$ 294,423
Proposed Industrial Rates - Rate Schedule No. 5					
Rate Component	2/11/2023	2/11/2024			
System Access Charge ($/Meter)	$ -	$ -	-		$ -
Energy Charge ($/kWh)	$ 0.03452	$ 0.04419	10,873,276	28%	$ 105,097
Proposed State Rates (Zone A) - Rate Schedule No. 19					
Rate Component	2/11/2023	2/11/2024			
System Access Charge ($/Meter)	$ 46.50	$ 57.00	16		$ 2,016
Energy Charge ($/kWh)	$ 0.10040	$ 0.12851	355,758	28%	$ 10,001
Proposed State Rates (Zone B) - Rate Schedule No. 19					
Rate Component	2/11/2023	2/11/2024			
System Access Charge ($/Meter)	$ 46.50	$ 57.00	18		$ 2,268
Energy Charge ($/kWh)	$ 0.11406	$ 0.12851	598,433	15%	$ 8,649
				Total Potential Increase to Revenue FY 24/25	$ 2,522,714

Forecast Summary

Revenues	20/21 (Actual)	21/22 (Actual)	22/23 (Preliminary)	21-23 % Growth	23/24 (Budgeted)	24/25 (Projected)	25/26 (Projected)	26/27 (Projected)	27/28 (Projected)	21-25 % Growth
Energy sales	11,865,205	12,167,458	12,102,650	1.0%	13,342,733	16,508,085	16,508,085	16,508,085	16,508,085	5.9%
Surcharge receipts	1,525,030	1,673,534	1,639,727	3.8%	-	-	-	-	-	
Other receipts	2,373,454	1,979,544	3,960,542	33.4%	4,356,526	2,134,934	2,158,817	2,188,903	2,219,678	-12.3%
Total	15,763,689	15,820,536	17,702,919	6.2%	17,699,259	18,643,019	18,666,902	18,696,988	18,727,763	-6.3%
Expenses										
Power acquisition	3,221,280	5,152,873	4,218,848	15.5%	4,365,770	4,371,353	4,377,102	4,383,025	4,389,125	0.1%
Operations & maintenance	4,407,884	4,495,731	5,162,445	8.6%	5,038,126	5,118,957	5,201,159	5,284,757	5,369,776	1.6%
Customer accounts	925,935	718,497	745,553	-9.7%	824,238	836,601	849,150	861,887	874,816	1.5%
Administrative & general	1,258,362	1,672,324	2,091,967	33.1%	2,097,985	2,141,714	2,166,519	2,212,428	2,259,471	1.9%
Debt & financing	1,629,058	2,486,462	2,549,585	28.3%	2,572,224	2,488,665	2,492,016	2,493,416	2,398,016	-1.7%
Total	11,442,519	14,525,887	14,768,398	14.5%	14,898,342	14,957,290	15,085,947	15,235,513	15,291,203	0.7%
Available for capital	4,321,169	1,294,649	2,934,521	-16.0%	2,800,917	3,685,728	3,580,955	3,461,476	3,436,560	5.7%
Capital outlay	6,324,646	5,710,088	7,817,194	11.8%	6,470,780	5,144,727	5,713,423	5,383,149	5,153,921	-5.1%
Bond/Loan proceeds	-	8,940,400	-		-	-	-	-	-	
County/MCMS funding	-	-	-		-	-	-	-	-	
County/MCMS repayments	143,638	168,227	97,931	-15.9%	-	-	-	-	-	-
Change in total reserves	(1,859,839)	4,693,188	(4,784,742)	78.6%	(3,669,863)	(1,458,999)	(2,132,468)	(1,921,673)	(1,717,361)	-13.3%
Reserves balances (end of year)										
Encumbered	1,185,720	690,400	390,045	-33.6%	1,404,492	1,446,627	1,468,011	1,489,710	1,511,730	1.9%
Restricted Reserves	55,247	8,719,967	5,083,384	4550.6%	66,179	12,341	12,635	12,935	13,243	-20.0%
Customer funds	1,167,026	916,130	913,991	-10.8%	892,195	872,542	861,216	852,889	844,562	-1.3%
Dedicated	386,667	75,000	-	-50.0%	-	-	-	-	-	#DIV/0!
Total other reserves	2,794,660	10,401,497	6,387,420	64.3%	2,362,866	2,331,510	2,341,861	2,355,534	2,369,536	0.1%
Contingency fund	2,557,352	(356,297)	(1,126,962)	-72.0%	(772,271)	(2,444,251)	(4,837,070)	(6,522,417)	(8,003,779)	234.1%
Total reserves	5,352,012	10,045,200	5,260,458	-0.9%	1,590,595	(112,741)	(2,495,209)	(4,166,883)	(5,634,244)	-113.6%

Includes $2.0 million of FEMA/OES expected reimbursement from 2022-2023 Winter storms

Updated to reflect lower power costs offset by $2.2million true-up Adjustment from Western

Includes the potential increase to revenue moving from year 2 directly to year 4 rates increased by $0.017 and increased Access Charge by $1 more than planned. High Impact increased by $5.

TRINITY PUD
HISTORICAL POWER COSTS
FY 11/12 THROUGH FY 23/24

FISCAL YEAR	KWH USAGE	ANNUAL POWER ACQUISITION COSTS	COST PER KWH
11/12	98,245,472	$ 2,131,005	$ 0.0217
12/13	98,046,742	$ 2,479,917	$ 0.0253
13/14	98,181,828	$ 2,425,626	$ 0.0247
14/15	94,241,352	$ 3,318,858	$ 0.0352
15/16	101,034,659	$ 3,979,409	$ 0.0394
16/17	108,676,572	$ 3,020,017	$ 0.0278
17/18	109,676,241	$ 1,360,867	$ 0.0124
18/19	107,665,663	$ 2,420,621	$ 0.0225
19/20	114,245,057	$ 2,936,470	$ 0.0257
20/21	127,947,935	$ 3,020,571	$ 0.0236
21/22	127,316,866	$ 4,948,466	$ 0.0389
22/23	122,273,970	$ 4,012,327	$ 0.0328
23/24	120,000,000	$ 4,130,944	$ 0.0344

FY 23/24 kWh sales originally assumed to be equal to FY 22/23.
Current analysis reflects lower kWh sales through December 2023.
FY 23/24 kWh sales have been adjusted down to reflect lower sales.

Trinity PUD
Rate Restructure - Year 3 impact
kWh Usage and Meter Count as of June 30, 2023
Increase Equal to DRS added to 2/11/2025 rates

	a	b	c	(b-a)*c*12 (b-a)*c
			# of Meters and YTD kWH at June 2023	Revenue Generated by rate change
Proposed Residential Rates (Zone A) - Rate Schedule No. 1				
Rate Component	2/11/2023	2/11/2024		
System Access Charge ($/Meter)	$ 31.00	$ 39.00	2523	$ 242,208
Energy Charge ($/kWh)	$ 0.05983	$ 0.08122	33,170,520	$ 709,517
Proposed Residential Rates (Zone B) - Rate Schedule No. 1				
Rate Component	2/11/2023	2/11/2024		
System Access Charge ($/Meter)	$ 31.00	$ 39.00	3,247	$ 311,712
Energy Charge ($/kWh)	$ 0.07122	$ 0.08122	33,356,281	$ 333,563
Proposed Commercial Rates (Zone A) - Rate Schedule No. 3				
Rate Component	2/11/2023	2/11/2024		
System Access Charge ($/Meter)	$ 46.50	$ 58.00	705	$ 97,290
Energy Charge ($/kWh)	$ 0.07758	$ 0.09959	19,700,046	$ 433,598
Proposed Commercial Rates (Zone B) - Rate Schedule No. 3				
Rate Component	2/11/2023	2/11/2024		
System Access Charge ($/Meter)	$ 46.50	$ 58.00	436	$ 60,168
Energy Charge ($/kWh)	$ 0.08761	$ 0.09959	6,581,109	$ 78,842
Proposed High Impact Rates (Zone A) - Rate Schedule No. 20				
Rate Component	2/11/2023	2/11/2024		
System Access Charge ($/Meter)	$ 82.50	$ 125.00	43	$ 21,930
Energy Charge ($/kWh)	$ 0.11656	$ 0.16300	2,975,347	$ 138,175
Proposed High Impact Rates (Zone B) - Rate Schedule No. 20				
Rate Component	2/11/2023	2/11/2024		
System Access Charge ($/Meter)	$ 82.50	$ 125.00	221	$ 112,710
Energy Charge ($/kWh)	$ 0.12857	$ 0.16300	14,273,819	$ 491,448
Proposed Industrial Rates - Rate Schedule No. 5				
Rate Component	2/11/2023	2/11/2024		
System Access Charge ($/Meter)	$ -	$ -	-	$ -
Energy Charge ($/kWh)	$ 0.04988	$ 0.05983	10,873,276	$ 108,189
Proposed State Rates (Zone A) - Rate Schedule No. 19				
Rate Component	2/11/2023	2/11/2024		
System Access Charge ($/Meter)	$ 46.50	$ 58.00	16	$ 2,208
Energy Charge ($/kWh)	$ 0.10040	$ 0.13130	355,758	$ 10,993
Proposed State Rates (Zone B) - Rate Schedule No. 19				
Rate Component	2/11/2023	2/11/2024		
System Access Charge ($/Meter)	$ 46.50	$ 58.00	18	$ 2,484
Energy Charge ($/kWh)	$ 0.11406	$ 0.13130	598,433	$ 10,317
				$ 3,165,352
			Weaverville	$ 1,764,109
			Other	$ 1,401,243

Credit Highlights

- S&P Global Ratings affirmed its 'BB+' long-term rating and underlying rating (SPUR) on Trinity Public Utility District (TPUD), Calif.'s previously issued electric revenue bonds.
- The outlook is stable.

Security

The bonds are secured by a first lien on electric system revenues. Total electric system debt outstanding as of fiscal year-end June 30, 2023, was $23.3 million. We view the lack of a debt service reserve on the series 2017 bonds as a credit weakness given the district's exposure to wildfires and weakened liquidity position. Additionally, in December 2021, the district entered into an agreement with Umpqua Bank for a $9 million loan that is on parity with the 2017 publicly rated debt. We view the legal provisions of the direct placement credit neutral but note that it could become a contingent liquidity risk should the district be held liable for damages above available liquidity and file for bankruptcy protection.

Credit overview

The rating reflects our opinion of the utility's insufficient cash position that is not commensurate with the amalgam of the state's determination that the utility faces pronounced exposure to wildfires. This is because 90% of its service territory lies within an area the California Public Utilities Commission designates as a Tier 2 elevated risk zone and the utility's inability to procure insurance covering wildfire claims in the wake of a $10 million wildfire liability claims in connection with a 2017 wildfire event. TPUD continues to address improvements in its 2023 updated wildfire-mitigation plan, which we view favorably, but these measures will take time to fully implement. S&P Global Ratings believes that TPUD's wildfire risk presents an ongoing exposure to the district, because future wildfires, even one much smaller than the 2017 Helena Fire that destroyed 72 homes, could result in additional significant claims for which the utility has, in our opinion, insufficient reserves. In addition, the district's limited number of customer accounts and below-average income levels would make any shared liability onerous on a per-customer basis.

Nevertheless, we note TPUD has generated historically robust fixed-charge coverage (FCC), although lower in recent years due to a rise in debt obligations, higher operating costs driven by inflation, and a weather event in 2022. Historically sound margins are in large part to its low-cost power and competitive rates. However, these underlying strengths are more than offset by the risks detailed above. We have embedded these potential risks throughout the district's enterprise and financial risk profiles.

The electric system's credit strengths include:

- Full requirements low carbon emitting power supply from Western Area Power Administration (WAPA) that is sufficient to meet long-term demand, although increased power prices during drought conditions can pressure financial metrics;
- Competitive electric rates (due to low-cost power supply from WAPA) that we expect will remain competitive despite annual double-digit rate increases annually through 2025; however, we note below-average income metrics may reduce affordability of electric rates; and
- FCC that has declined to about 1.5x in fiscal 2023 from 2.0x in fiscal 2021, which is still stronger than that of peers at the rating level and, based on our analysis of management-provided projections, FCC is expected to rise and remain sound due to expected lower power costs due to strong water year and double-digit rate increases through 2025.

Offsetting these credit strengths are the electric system's:

- Service area economic fundamentals, reflecting the diverse but small and relatively shallow customer base that exhibits incomes that are about 32% below the state average;
- Decline in liquidity to $1.3 million for fiscal 2023, or only 40 days of operating expenses, which we consider extremely low, from $9 million in fiscal 2018. When including the two new $1 million lines of credit with CoBank as of November 2023 total liquidity would be approximately $3.3 million for fiscal 2023 or 90 days of operating expenses; and
- Moderate debt and liabilities profile, suggested by Trinity's pro forma debt-to-capitalization ratio of 38% for fiscal 2023, with no future debt plans but a large capital plan budgeted at $27 million through fiscal 2028.

Environmental, social, and governance

Environmental physical risks are negative within our credit rating analysis given the substantial amount of power lines and customer meters within elevated fire threat areas, the history of wildfires in the service area, and now TPUD's inability to maintain wildfire insurance. TPUD has various improvements in its wildfire-mitigation plan including interphase spacers, aerial patrols, infrared inspections, disabling automatic reclosers during wildfire season, and frequent vegetation management. In addition, the district believes the most impactful could be its work to increase rights of way to 130 feet from 20 feet to reduce tree contacts and wildfire risk. This project is on federally managed land and in the planning phase, with an environmental impact report expected to be completed in fiscal 2024. In addition, the history of drought conditions in California can exacerbate wildfire risk. Nevertheless, we view positively the district's power supply entirely from non-carbon-emitting hydro resources.

In our opinion, governance, risk management, culture, and oversight are also negative to credit quality given management's expectation of maintaining a low level of liquidity in the face of operational risk stemming from potential wildfires. Management's policies and procedures include a cost pass-through mechanism on its electric rates, long-term financial planning, and capital planning.

We believe the district's social capital factors are neutral in our credit rating analysis given the low cost of power driving competitive rates, which is modestly offset by the below-average income indicators that could pressure planned rate increases, complicated by high inflation.

Outlook

The stable outlook reflects our view of TPUD's significant ongoing efforts to mitigate wildfire exposure and its rate flexibility given the benefits of its low-cost, non-carbon-emitting power supply. We believe TPUD will continue to pass through higher power costs to its customers but not plan to materially bolster reserves as a contingency for potential future wildfire claims.

Downside scenario

We could lower the rating, potentially by multiple notches, over the next two years if TPUD faces wildfire claims beyond its financial capacity, and if it is unable or unwilling to raise rates or access capital markets to fund said damages.

Upside scenario

Over the next two years, we are unlikely to raise the rating because the risk from wildfires will remain considerable. Actions taken by TPUD and the state can reduce the utility's exposure to wildfires, but these actions could be politically unpalatable and/or require sustained efforts over multiple years.

Credit Opinion

Enterprise Risk

Limited but stable economic base

TPUD serves a small and shallow customer base throughout Trinity County, and its customer base is primarily residential and diverse. The leading customer is Trinity River Lumber, whose sales have remained stable in recent years despite stronger lumber prices during the pandemic. Trinity County has historically depended heavily on the timber industry, with current growth in the cannabis-related industry; however, the state and federal government, and public administration sectors account for the largest percentage of employment in the county.

Low cost, reliable, and carbon-free power supply is a credit strength

TPUD is the only public power agency with a full-requirements allocation of economical WAPA energy. The contract with WAPA, effective January 2005, was extended 20 years. This agreement has furnished the district with a reliable, carbon-free, low-cost source of power, which has contributed to low electric rates and robust margins. We view the district's priority rights to the first 25% of power from WAPA's Trinity River Division as a credit strength, mainly because of the power's status as eligible renewable energy under state guidelines. This also effectively exempts the utility from stringent California emissions regulations. WAPA has an obligation to meet Trinity's load even during years of extremely poor stream flow conditions, including drought conditions. We understand that the allocation is sufficient to meet Trinity's current needs and any potential growth, with a supply equal to almost 3x the PUD's native load.

Competitive electric rates despite planned rate increases

The district sets rates to recover power supply costs, maintain low rates, fund variable expenses, maintain 1.35x coverage, and fund capital projects, but indicated it has not set rates to significantly build up liquidity. TPUD has planned rate increases of about 10%-12% for the system access charge annually through 2025 and an increase to the energy charge per kilowatt-hour, and when needed has implemented its monthly drought surcharge to recover WAPA's larger true-ups during drought conditions. Although Trinity's electric rates are what we consider favorable, we believe it has somewhat limited rate-making flexibility due to its customers' low income levels, the region's shallow economy, and the utility's limited customer base.

Financial Risk

Low liquidity position that is not expected to materially rise

After the 2017 Helena Fire, for which the district settled at $10 million under its insurance policy, management now reports that the utility is unable to procure reinsurance for wildfire liability. This exposure is meaningful as any future wildfire claims or settlements would have to be paid out of cash on hand. Additionally, TPUD's inability to acquire insurance is indicative of the magnitude of the perceived risks. In the event of a wildfire event, we believe interim liquidity or access to capital markets could be costly or difficult to obtain. Coupled with the district's small amount of reserves, which has declined for wildfire-mitigation projects, we believe any future settlements or direct wildfire damages could be onerous for the district.

Additionally, we understand a winter storm in 2022-2023 resulted in the need to spend an additional $3 million for storm repairs; management expects to receive $2 million in Federal Emergency Management Agency (FEMA) reimbursement funds. In fiscal 2023, total cash was about $1.3 million, which we consider low given the wildfire risk and capital investments for wildfire mitigation efforts. The district does not plan to materially build up cash; with maintenance between $2 million and $4 million annually, this level of liquidity is low against the backdrop of wildfire risks. Nevertheless, we view favorably that the district entered into two line of credit agreements in the amount of $1 million each with CoBank. These committed lines of credit provide additional liquidity to the utility although still overall nominally low.

Sound FCC on average, although volatile in recent years, that, based on management-provided projections, is expected to rise

TPUD's FCC declined in recent years but is projected to rise and remain robust through 2027 given rate increases and lower projected WAPA power costs. The lower FCC in 2020 was due to higher power costs related to drought conditions (after which management implemented the drought surcharge). In fiscal 2022 and 2023, the lower metrics were driven by a rise in debt service obligations from the series 2021 obligations and higher operating expenses due to inflation. Based on our analysis of management-provided projections, FCC is expected to rise to above 1.6x (2024-2027) and be maintained at a robust level due to the planned double-digit rate increases and lower power costs from a strong water year in 2023.

High capital spending during the next five years with no debt plans

We have assessed the electric system's debt and liabilities as moderate given the district's debt-to-capitalization ratio of 38% for 2023. The district has no future debt plans and used its $9 million direct placement loan for current projects. Capital improvements consists of replacements and improvements primarily to mitigate wildfire exposure. If excess cash flow declines, this could result in slower progress, through its capital plan and deferred maintenance that is needed to prevent wildfire risk and to maintain redundancy in the system.

	A	B	C	D
1	***Trinity Public Utility District, CA--Key credit metrics***			
2		**--Fiscal year ended June 30--**		
3		**2023**	**2022**	**2021**
4	**Operational metrics**			
5	Electric customer accounts	7,296	7,323	7,350
6	% of electric retail revenues from residential customers	58	50	53
7	Top 10 electric customers' revenues as % of total electric operating revenue	15	15	13
8	Service area median household effective buying income as % of U.S.	68	68	66
9	Weighted average retail electric rate as % of state	N.A.	48	55
10	**Financial metrics**			
11	Gross revenues ($000s)	17,159	15,892	15,066
12	Total operating expenses less depreciation and amortization ($000s)	12,463	11,546	10,136
13	Debt service ($000s)	2,486	1,564	1,566
14	Debt service coverage (x)	1.9	2.8	3.1
15	Fixed-charge coverage (x)	1.5	1.7	2.1
16	Total available liquidity ($000s)*	3,301	1,571	5,953
17	Days' liquidity	97	50	214
18	Total on-balance-sheet debt ($000s)	25,123	26,903	19,706
19	Debt-to-capitalization (%)	46	49	43
20	*Total available liquidity includes available committed credit line balances, where applicable. Debt service coverage--Revenues minus expenses divided by debt service. Fixed-charge coverage--Sum of revenues minus expenses minus total net transfers out plus capacity payments (or their proxy), divided by the sum of debt service plus capacity payments (or their proxy). N.A.--Not available.			
21				

Related Research

Through The ESG Lens 3.0: The Intersection Of ESG Credit Factors And U.S. Public Finance Credit Factors , March 2, 2022